O'DEA EARLE

April 25, 2014

Ms. G. Cheryl Blundon
Board of Commissioners of Public Utilities
120 Torbay Road, P.O. Box 12040
St. John's, NL A1A 5B2

Dear Ms. Blundon:

Re: Newfoundland and Labrador General Rate Application

Re: Pre-Filed Evidence of C. Douglas Bowman

Please find enclosed the original and twelve (12) copies of the Pre-Filed Evidence of C. Douglas Bowman which is being filed on behalf of the Consumer Advocate in relation to the above noted Application.

A copy of the letter, together with enclosure, has been forwarded directly to the parties listed below.

If you have any questions regarding the filing, please contact the undersigned at your convenience.

Yours very truly,

O'DEA, EARLE

THOMAS JOHNSON

TJ/cel
Encl.

cc: Newfoundland & Labrador Hydro
P.O. Box 12400
500 Columbus Drive
St. John's, NL A1B 4K7
Attention: Geoffrey P. Young, Senior Legal Counsel

Newfoundland Power
P.O. Box 8910
55 Kenmount Road
St. John's, NL A1B 3P6
Attention: Gerard Hayes, Senior Legal Counsel

Vale Newfoundland and Labrador Limited
c/o Cox & Palmer
Suite 1000, Scotia Centre
235 Water Street
St. John's, NL A1C 1B6
Attention: Thomas J. O'Reilly, Q.C.

Corner Brook Pulp & Paper Limited,
c/o Stewart McKelvey
Cabot Place, 100 New Gower Street
P.O. Box 5038
St. John's, NL A1C 5V3
Attention: Paul Coxworthy

Miller & Hearn
PO Box 129
450 Avalon Drive
Labrador City, NL A2V 2K3
Attention: Ed Hearn, Q.C.

Olthuis, Kleer, Townshend LLP
229 College Street
Suite 312
Toronto, ON
M5T 1R4
Attention: Nancy Kleer

House of Commons
Confederation Building, Room 682
Ottawa, ON K1A 0A6
Attention: Yvonne Jones, MP Labrador/Christian von Donat

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

IN THE MATTER OF
the *Public Utilities Act*, R.S.N. 1990,
Chapter P-47 (the "Act");

AND

IN THE MATTER OF
a General Rate Application (the "Application")
by Newfoundland and Labrador Hydro for
approvals of, under Section 70 of the Act, changes
in the rates to be charged for the supply of power
and energy to Newfoundland Power, Rural Customers
and Industrial Customers; and under Section 71 of the
Act, changes in the Rules and Regulations applicable
to the supply of electricity to Rural Customers.

PRE-FILED EVIDENCE OF C. DOUGLAS BOWMAN

April 25, 2014

PRE-FILED EVIDENCE
OF
C. DOUGLAS BOWMAN

Evidence Outline

List of Exhibits

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

IN THE MATTER OF the *Public Utilities Act*, R.S.N. 1990, Chapter P-47 (the "Act");

AND

IN THE MATTER OF a General Rate Application (the "Application") by Newfoundland and Labrador Hydro for approvals of, under Section 70 of the Act, changes in the rates to be charged for the supply of power and energy to Newfoundland Power, Rural Customers and Industrial Customers; and under Section 71 of the Act, changes in the Rules and Regulations applicable to the supply of electricity to Rural Customers.

PRE-FILED EVIDENCE OF C. DOUGLAS BOWMAN

My name is Doug Bowman. This document was prepared by myself, and is correct to the best of my knowledge and belief. I have been retained by the Government appointed Consumer Advocate to provide expert advice and evidence to the Consumer Advocate in response to Newfoundland and Labrador Hydro's ("Hydro's") 2013 General Rate Application.

A summary of my background and qualifications is provided in ***Exhibit CDB-1***. I have both a B.S. and an M.S. in Electrical Engineering from the State University of New York at Buffalo and 37 years of experience in the electricity services and consulting industry. My primary expertise includes electricity services costing and pricing and power sector restructuring, regulation and markets. I am currently an independent Energy Consultant working out of my office located in Warrenton, Virginia.

Prior to becoming an independent consultant, I was employed by KEMA Consulting, Nexant Inc., Pace Global Energy Services, International Resources Group, CSA Energy Consultants and Ontario Hydro. I have taken part in the regulatory process in this Province on behalf of the Consumer Advocate since 1996, and have submitted testimony before this Board seven times previously as an expert witness on cost of service and rate design at Newfoundland Power's 1996 *Application by Petition for Approval of Certain Revisions to its Rates, Charges and Regulations*, at Newfoundland and Labrador Hydro's 2001 *General Rate Proceeding*, at Newfoundland Power's 2003 *General Rate Application*, at Newfoundland and Labrador Hydro's *2003 General Rate Application*, at Newfoundland and Labrador Hydro's *2006 General Rate Application*, at Newfoundland Power's *2007 General Rate Application* and at Newfoundland and Labrador Hydro's 2009 *Application concerning the Rate Stabilization Plan components of the rates to be charged Industrial Customers*. I have also appeared twice before the Nova Scotia Utility and Review Board as an expert witness on cost of service and rate design, and while at Ontario Hydro, I was involved with the regulatory process in the areas of generation and transmission planning, demand/supply integration, operations, rate design and customer service.

Section 1 of my Pre-filed Evidence summarizes my review of Hydro's evidence with regard to this Application, while **Sections 2 through 12** provide reviews of: the time between GRAs, the RSP, the disposition of RSP balances, the Industrial Customer rate design, the proposed changes to the Newfoundland Power wholesale rate, curtailable/interruptible rate options for Newfoundland Power and the Industrial

Customers, the Corner Brook Pulp & Paper generation credit, the classification of purchases from wind generators in the cost of service study, the rural rate subsidy, the abandonment of the wheeling rate and the key performance indicators.

1. Summary of Evidence

A summary of my recommendations relating to Hydro's 2013 General Rate Application follows. My recommendations are provided within the context of the 2013 GRA and cost of service study, and are made for the Board's consideration in its Order on the 2013 GRA. I note that when a utility's rate of return is fixed by legislation as it is for Hydro by OC2009-063, its performance whether rising or falling cannot influence its allowed rate of return, so there is a tendency for the utility to pay less attention to regulatory commitments and directives, customer satisfaction, reliability of service and cost control. Under such circumstances it is important that the regulatory board ensure that the utility's performance is not deteriorating. My recommendations are made with this in mind.

a) I recommend that the Board order Hydro to file its next General Rate Application (GRA) within three years following the issuance of an Order on the 2013 GRA, and perhaps two years given the major cost of service-related events on the near-term horizon.

b) I recommend that the Board order the continuing operation of the RSP, but with the following modifications:

    i. Eliminate the load variation component which is a deterrent to efficient rate design;

ii. Limit the number of components of the RSP to only those that relate to bulk power supply on the Island Interconnected System, including the fuel cost component and the hydraulic production component; and

iii. Incorporate a dead-band to promote efficient fuel procurement and management practices by Hydro.

c) I recommend that Hydro and the Parties propose for the Board's consideration a methodology for distributing the balances in the RSP in a manner that reduces the volatility of rates over the period to 2017; i.e., reduces the volatility of rates forecast in NP-NLH-32 and brought on by new projects such as Hydro's proposed 100 MW combustion turbine.

d) I recommend that Hydro file for the Board's consideration an IC rate consistent with the rate design Hydro agreed to with the ICs during the 2008 study documented in Exhibit 12 (Table 1, page 10). The rate design should incorporate the interruptible rate option addressed below. The filing should be consistent with the 2013 GRA and cost of service, and I recommend it form part of the Board's Order on the 2013 GRA.

e) I recommend that the Board Order in its submission on the 2013 GRA a rate design for NP consistent with the design agreed to by the Parties at the 2006 GRA such as the alternatives presented in NP-NLH-152 and CA-NLH-26.

f) I recommend that Hydro file for the Board's consideration a curtailable/interruptible rate design for NP curtailable service customers and for the Industrial Customers. The curtailable service rate design for NP customers should address the design issues raised in Exhibits 9 and 11, and identify the implications in the 2013 cost of service study. The interruptible rate option for the ICs should be consistent with the treatment of NP curtailable service, include an assessment of the interruptible load contract with CBPP in light of the generation credit, include an assessment of the fairness of the CBPP interruptible contract relative to the rates offered other ICs, and recognize that the ICs are already receiving a rate subsidy from the small customers in the Province (proposed in the 2013 GRA consistent with OC2013-089). The curtailable/interruptible rate filing should be consistent with the 2013 GRA and cost of service, and I recommend that it form part of the Board's Order on the 2013 GRA.

g) I recommend that the Board deny Hydro's proposal to permanently instate the supply agreement with CBPP. I recommend that Hydro file for the Board's consideration a study of the CBPP supply agreement in its entirety taking into consideration the new interruptible component of the contract, the subsidy being received by the ICs owing to the IC rate phase-in, and the reduced value of energy following commissioning of Muskrat Falls. Further, I recommend the study consider the pros and cons of separate contracts with Deer Lake Power generation and CBPP to increase transparency, and optimize the conversion efficiency of water to electrical energy at the Deer Lake Power facility. The filing should be consistent with the 2013 GRA and cost of service, and I recommend it form part of the Board's Order on the 2013 GRA.

h) I recommend that the Board direct Hydro to file a study on the appropriate capacity/energy classification of purchases from wind generation on the Island Interconnected system for use in the cost of service study. The filing should be consistent with the 2013 GRA and cost of service, and I recommend that it form part of the Board's Order on the 2013 GRA.

i) I recommend that the Board direct a portion of Hydro's return toward payment of the rural subsidy, a subsidy mandated by Government, Hydro's shareholder. If it is determined that a portion of the rural rate subsidy is to continue to be subsidized by NP and Labrador Interconnected customers, I recommend that the Board direct that it be allocated to NP and Labrador Interconnected customers on the basis of revenue requirement or number of customers.

j) I recommend that the Board direct Hydro to keep the wheeling rate active until a need arises to replace it with something different in the future.

k) I recommend that the Board direct Hydro to file an approach to identifying functionally-oriented financial targets and reporting in a consistent and meaningful manner without incurring the costs associated with undertaking a cost of service study.

l) I recommend that the Board direct Hydro to file a strategy focused on improving customer service including a time-bound scope of work and plan for completing the undertaking, and including annual performance targets for gauging progress. I recommend that upon completion the strategy be submitted to relevant stakeholders for review and comment.

2. Time Between General Rate Application (GRA) Filings

Seven years have elapsed since the last GRA. This is excessively long. As the Application shows, there have been numerous events impacting Hydro's costs and rates since the 2006 GRA. The response to CA-NLH-24 indicates there are 18 Government directives to be taken into account by the Board in the 2013 General Rate Application, and OC2013-089 is in direct response to the very low rates the ICs have been paying since the 2006 GRA owing to the freeze on IC rates arising from the high level of rate volatility brought on by the RSP. Had a GRA been submitted, this issue could have been dealt with by the Parties and the Board without Government intervention.

Hydro states its agreement with Board Order No. P.U. 13 (2013) that a three-year period between GRAs is generally consistent with sound utility regulation (see PUB-NLH-74 and PUB-NLH-75). I also believe that three years between GRAs should be the target given the regulatory format in this Province (cost of service based regulation rather than incentive based regulation), and given the significant events on the near-term horizon, including the commissioning of Muskrat Falls and the associated transmission link, the transmission link with Nova Scotia, the new combustion turbine at the Holyrood site, the IC rate phase-in, and the outage events of the 2013/14 winter and the potential projects that may result from the Inquiry.

I recommend that the Board direct Hydro to file its next GRA three years following the issuance of an Order on the 2013 GRA, and perhaps within two years given the major cost of service-related events on the near-term horizon.

3. The Rate Stabilization Plan (RSP)

Hydro proposes to continue with the current RSP design with the exception that allocation of the load variation component be on the basis of energy ratios (see July 2013 Rate Stabilization Plan Evidence, page 13, lines 3 to 7). This is the same RSP design proposed by Hydro at the 2006 GRA when the Parties agreed to examine re-design of the RSP to better meet design objectives (see Review of Rate Stabilization Plan, page 1, RSP-CA-NLH-6 Attachment 2, page 5 of 27). The objectives of the RSP agreed to by the Parties for the conduct of the study included (page 7 of the same document):

- *To provide for acceptable levels of rate and revenue stability for customers and Hydro;*
- *To provide for regulatory efficiency by allowing changes in rates to recover changes in prudently incurred fuel costs without requiring a general rate proceeding;*
- *To provide for timely changes in rates and avoid material changes in the price signal that would promote appropriate consumption decisions by customers;*
- *To provide for fair apportionment of costs among the customers impacted by the RSP;*
- *To mitigate material intergenerational equity concerns;*
- *To provide for ease of understanding; and*
- *To provide for ease and efficiency of administration.*

No provisions in the RSP should provide an incentive to Hydro or its customers to operate in a manner that is inconsistent with the least cost power policy of the Province and generally accepted sound utility practice.

By agreeing to undertake the study of the RSP the Parties were acknowledging that Hydro's proposed RSP design was inadequate. Unfortunately, Hydro failed to complete the study, and the RSP design remains unresolved. Hydro's proposed RSP design was inadequate to meet the requirements of the Parties in 2006 and remains inadequate to meet the needs of customers today.

There are a number of concerns with the RSP design, as follow:

a) ***Inconsistent with Regulatory Practice Elsewhere:*** The RSP design is not used by utilities elsewhere in North America. As stated in V-NLH-13: "*Hydro is unaware of other utilities in North America with a rate stabilization plan similar to Hydro's*".
b) **RSP Provides Limited Value to Customers**: Hydro acknowledges in CA-NLH-43 that an alternate RSP design is feasible and may in some ways simplify the calculation. In PUB-NLH-290, Hydro was asked to describe in detail the "*significant value*" that the RSP provides to customers. In its response, Hydro identifies disadvantages to customers, including large accumulated balances such as that in the 2002/03 time frame that can lead to allocation and rates policy issues. The only advantage that Hydro was able to identify was that relative to the fuel adjustment clause that was in place prior to the introduction of the RSP in 1986, the current RSP design can smooth customer rate impacts from the volatility of fuel costs. However, the smoothing is in large part related to the time

frame that rates are adjusted. In the fuel adjustment clause that Hydro had in place prior to 1986, rates were adjusted monthly. This "disadvantage" could have been mitigated by adjusting rates annually instead of monthly. Further, as shown in NP-NLH-32 (Attachment 1), rate impacts are not forecast to be particularly smooth under the proposed RSP design, with NP rates expected to increase 1.9% in 2014, 17.7% in 2015, 2.8% in 2016 and a further increase of 5.2% in 2017. It was the volatility of the RSP that brought on the IC rate freeze in 2008.

c) ***Problems when Large Balances Accumulate***: As noted by Hydro, the current RSP design can disadvantage consumers when large balances accumulate (PUB-NLH-290). The IC class is currently paying only about 65% of the cost of power determined in the 2013 cost of service study (see RSP-CA-NLH-12, Attachment 1). As stated by Hydro in RSP-CA-NLH-12, the subsidy to the IC class granted through OC2013-089 is $37.6 million. To put the subsidy into perspective, $37.6 million is more than double the average annual revenue received from the entire IC class during the period from 2008 to 2012 (see CA-NLH-182). Based on the revenues that should have been collected from the IC class during the period 2008 through 2012 (i.e., if rates had not been frozen and the load variation component of the RSP had been allocated on the basis of energy ratios as proposed by Hydro in the 2013 and 2006 GRAs), the $37.6 million subsidy received by the IC class is equivalent to more than 1 ½ years of free power (based on IC class average annual consumption during 2008 to 2012 period – see CA-NLH-182). No such subsidy has been offered Newfoundland Power's customers, but if it had, it would be equivalent to $627.3 million (based on average annual revenues received from

NP during the 2008 to 2012 period – see CA-NLH-182). The $37.6 million subsidy transferred from NP customers to the ICs averages to about $147/customer (based on 256,000 customers according to NP website: http://www.newfoundlandpower.com/AboutUs/). As the Board states in Order P.U. 40(2013) (page 3, line 48 and page 4, line 1), "the RSP adjustment has not operated normally for the Industrial Customers since 2008". The improper operation of the IC RSP since 2008 has resulted in IC rates that are far below costs, so much so that the Government found it necessary to issue OC2013-089 to phase in IC rates to the full cost of power over three years. As a result, the IC rates will continue to under-collect for another two years. It is doubtful that the small customers in the Province who are paying the subsidy to the ICs view the current design of the RSP as "*providing significant value to customers*" as Hydro claims (see PUB-NLH-290).

d) ***RSP Provides Limited Value to Hydro:*** In PUB-NLH-292, Hydro lists a number of disadvantages of the RSP relative to the fuel adjustment clause that was in place prior to 1986, including: high financing costs, increased risk of RSP balance recovery, delays in receiving cash flows, increased complexity in rates and associated regulatory effort, difficulty in communicating the operation of the RSP to others, and increased administration requirements. The only advantage that Hydro could identify is that relative to the fuel adjustment clause in place prior to 1986, there is increased customer satisfaction owing to reduced rate volatility. However, as already discussed this "disadvantage" could have been mitigated by adjusting rates annually instead of monthly.

e) ***Reduced Incentive to Improve Rate Designs:*** As stated in CA-NLH-159, Lummus would revise the energy component of the rates for both NP and the ICs if the RSP were abandoned. By setting the second block energy rate at a level that better reflects Holyrood fuel costs the NP and IC rate designs would be improved in two ways: 1) Hydro would be protected from variations in load because the revenues arising from changes in load would track changes in costs; and 2) the efficiency of the rate design would be improved because customers would be making consumption decisions on the basis of a price signal reflecting the marginal cost of energy. With the RSP in place, Hydro proposes to forego these benefits of improved rate design.

f) ***RSP has Limited Shelf-Life***: In CA-NLH-181, Hydro states that the RSP in its present form mainly accounts for variations in Holyrood fuel costs, so once Holyrood is permanently shut down, there will no longer be a need for the RSP in relation to Holyrood. Muskrat Falls is scheduled for service in 2017 (CA-NLH-22), meaning the RSP may no longer be needed three years following an Order on this GRA.

g) ***Failure to Complete RSP Review***: In CA-NLH-43, Hydro states "*the existing RSP rules have been adjusted over the past three GRAs, resulting from extensive analysis and discussion among the Parties*". It is true that the RSP has received extensive discussion over the last three GRAs. However, the review of the RSP design agreed to by the Parties following the 2006 GRA was never completed. Further, Hydro has not proposed an alternative RSP design, stating in CA-NLH-43: "*Hydro does not believe that a reasonable alternate design of the RSP can be* *developed and fully tested within the required timeframe for the response to this question*" (although Hydro provides no support for this statement). It is evident that Hydro has chosen not to evaluate the RSP design relative to its design objectives in spite of its commitment to the Parties to do so seven years ago. Hydro goes on to say "*given the limited operating time remaining for the Holyrood plant, Hydro recommends that the existing RSP rules remain in place with the exception that the load variation component of the RSP be shared on a proportionate energy basis*". In spite of the Parties' best efforts, Hydro has not evaluated the RSP relative to its design objectives, and has filed no alternative RSP designs for the Board's consideration.

h) ***Alternatives to RSP***: In PUB-NLH-285, Hydro identifies a number of fuel adjustment clauses utilized by other utilities in North America. The fuel adjustment clause accounts for differences between the total cost of fuel burned and the total fuel-related revenues recovered. The calculation can be straightforward. For example, Northern Indiana Public Service Company has a fuel adjustment factor based on fuel expenses in the period divided by sales in the same period. Further, some jurisdictions such as Portland General Electric (see PUB-NLH-285, Attachment 4) compute the fuel cost adjustment annually, and incorporate a dead-band such that rates are adjusted only when fuel cost differences fall outside a pre-specified range. Portland's fuel cost adjustment is based on fuel costs forecast for the next calendar year, less the revenues that would occur at prices determined in the Company's most recent rate case. A dead-band provides incentive for the utility to manage fuel costs, and might be based on a percentage (i.e., plus/minus 10%), or a defined cost figure (i.e., plus/minus $10 million). The point is that although Hydro has failed to file alternatives to its proposed RSP design, alternatives do in fact exist.

In summary, the RSP design is not meeting its design objectives. It is unduly complex, provides little or no value to consumers or Hydro, has limited shelf-life with the upcoming retirement of Holyrood, and raises inter-generational equity concerns. It does not appear to be stabilizing rates (the instability of IC rates brought on by the RSP is why IC rates were frozen back in 2008, and the response to NP-NLH-32 indicates the RSP will result in continued rate instability going forward). It reduces the incentive for Hydro to pursue efficient rate designs, has significant disadvantages when large balances build up in the deferral accounts, and is inconsistent with regulatory practice elsewhere.

Because alternatives to the proposed RSP design have not been filed, I recommend that the Board order the continuing operation of the RSP, but with the following modifications:

1) Eliminate the load variation component which is a deterrent to efficient rate design;
2) Limit the number of components of the RSP to only those that relate to bulk power supply on the Island Interconnected System, including the fuel cost component and the hydraulic production component; and
3) Incorporate a dead-band to promote efficient fuel procurement and management practices by Hydro.

These modifications will eliminate some of the concerns with the RSP design identified above and will move it closer to meeting the design objectives agreed to by the Parties on the study to examine the re-design of the RSP (Review of Rate Stabilization Plan, RSP-CA-NLH-6 Attachment 2, page 5 of 27).

4. Disposition of RSP Balances

In July 2013 the hydraulic production component of the RSP had a balance owing to customers of $36.7 million (see NP-NLH-18). A balance has also been accumulating in the load variation component of the RSP since the balance was disbursed to customers on August 31, 2013 in accordance with Order No. P.U. 26 (2013). The methodology used to dispose of balances in the RSP should be reviewed in light of the limited remaining operating time of the Holyrood plant. As Hydro indicates in CA-NLH-181, there will no longer be a need for the RSP in its present form once Holyrood is permanently shut down.

The forecast rate changes resulting from the RSP are significant. According to NP-NLH-32, forecast rate changes to NP owing to the RSP are: 1.9% in 2014, 17.7% in 2015, 2.8% in 2016 and 5.2% in 2017. Therefore, I recommend that Hydro and the Parties propose for the Board's consideration a methodology for distributing the balances in the RSP in a manner that reduces the volatility of rates over the period to 2017; i.e., reduces the volatility of rates forecast in NP-NLH-32 and brought on by new projects such as Hydro's proposed 100 MW combustion turbine. The filing should be consistent with the

2013 GRA and cost of service, and should form part of the Board's Order on the 2013 GRA.

5. Industrial Customer (IC) Rate Design

A review of the IC rate design was carried out following the 2006 GRA as a result of the Parties' Agreement (see GRA Application, Volume II, Exhibit 12). Hydro and the ICs reached agreement on a rate design during the 2008 study, yet Hydro has not proposed to implement the rate design in the 2013 GRA. Hydro indicates in CA-NLH-78 that the rate design in Table 1, page 10 of Exhibit 12 would encourage economic efficiency while maintaining other rate design principles. However, in the same RFI response Hydro explains that the existing rate structure should be maintained because Vale's load is forecast to ramp up over the next several years and the phase-in of IC rate levels for September 1, 2013, 2014 and 2015 which would mute any price signals, so "*there is no alternative rate design available*".

As for Vale, they already have a special rate recognizing that operations will be ramping up by paying a capacity charge on the basis of monthly, rather than annual, demand. They could be ignored until operations are fully underway. As for the other customers, the signal may be muted owing to the rate phase-in, but that does not mean that "*there are no alternative rate designs available*" that better meet design objectives than the rate design in place today. Further, the rate phase-in for the ICs ends on September 1, 2015, which is likely less than a year after the Board will issue an Order on this Application. The problem is that there is no incentive for Hydro to pursue implementation of the rate design presented in Exhibit 12 because the load variation component of the RSP protects them when loads vary from forecast. Abandonment of the load variation component of the RSP as I recommended above would provide incentive for Hydro to pursue alternative rate designs such as that included in Table 1, page 10 of Exhibit 12.

In summary, I recommend that Hydro in consultation with the ICs submit for the Board's consideration an IC rate consistent with the rate design agreed to by Hydro and the ICs during the 2008 study documented in Exhibit 12 (Table 1, page 10). The rate design should incorporate the interruptible rate option addressed in Section 7 of my pre-filed evidence. The filing should be consistent with the 2013 GRA and cost of service, and I recommend it form part of the Board's Order on the 2013 GRA.

6. Proposed Changes to Newfoundland Power (NP) Rate

Hydro is proposing changes to the NP rate, in particular, a 128% increase in the capacity charge from \$4.00/kW/month to \$9.12/kW/month (see 2013 GRA Application, Volume 1, page 4.4, Table 4.1). The proposed increase in the demand charge:

i. ignores that the current demand charge was agreed upon by the Parties during Hydro's 2006 GRA (see 2013 GRA Application Volume 1, page 4.3, lines 7 to 9),
ii. does not reflect current marginal cost forecasts (see CA-NLH-157) and the principle agreed to by the Parties that rate designs will include

consideration of marginal costs over a number of years into the future (see GRA Application, Volume II, Exhibit 9, page 10), and

iii. has been proposed without input from NP or any of the Parties, and without regard to the potential impact on NP's cash flow (see NP-NLH-119).

Hydro believes that "*no changes should be made to the IC rate structure until the future marginal cost structure is known*" (see GRA Application, Volume 1, page 4.7, lines 11 to 12), yet proposes to more than double the NP capacity charge. No utility "knows" its marginal cost structure – that is why it is called a forecast, but considering that Hydro is not in a position to "*determine the appropriate price signals*" (see CA-NLH-32) , it is not clear why it would propose to more than double the NP demand charge. If unable to determine the appropriate price signal, it is preferable to apply the rate increase in a way that least distorts the current rate and the resulting impact on customers, particularly when the current rate is based on an agreement of the Parties.

Two alternative rate designs consistent with this approach have been raised in the RFI process: 1) apply the increase proportionally to each rate component while maintaining the size of the first energy block (see NP-NLH-152), and 2) leave the capacity charge unchanged at $4/kW/month and collect the remainder of the revenue requirement in the tail-block energy charge while keeping the first block quantity and charge as proposed (see CA-NLH-26). Both of these rate designs are superior to the rate proposed by Hydro. Hydro proposes that during GRA negotiations "*the parties consider whether a fully-cost-*

based demand rate to NP is appropriate under all of the circumstances" (see CA-NLH-177). I recommend that the Board Order in this GRA a rate for NP that is consistent with the alternatives presented in NP-NLH-152 and CA-NLH-26.

7. Curtailable/Interruptible Rate Options for NP and the ICs

The design and treatment of NP's curtailable load in the cost of service study should be revised to provide incentive for NP to retain, and pursue, curtailable service customers. The outage events of the winters of 2012/13 and 2013/14 make it clear that interruptible/curtailable rates can provide significant value to the power system. However, the current design of the NP curtailable service rate is sub-optimal as explained in the GRA Application, Volume II, Exhibit 11 (pages 25 and 26) because NP's Curtailable Service Customers are interrupted to shave NP's peak load which provides limited value to the system. These customers should only be interrupted for system reliability reasons to provide greater assurance that the curtailable load will be available when there is a system need. Customers are much more likely to remain on or sign on for the curtailable service option if they know they will be interrupted only during system emergencies. The report on the Review of Demand Billing for NP (GRA Application, Volume II, Exhibit 11 page 26) which includes the report on the Review of Demand Billing to NP, states:

> *"Hydro and NP agree in principle with adjusting the billing demand to reflect available curtailable load. However, details on how the curtailable load amount is determined, tested, and modified on an ongoing basis require review.* ***Hydro and NP agree to propose changes to the wholesale demand and energy rate to***

accommodate a change in the treatment of NP's curtailable load at Hydro's next GRA, due to the impact on other customers. *That is, implementing such a mechanism for the curtailable load has Cost of Service implications and should be tested during a GRA process where all customer groups have an opportunity to offer evidence or argument on the matter." (emphasis added)*

I agree with this statement now as I did in 2008 during the review of the NP rate documented in Exhibit 11, yet in GRA Application Volume II, Exhibit 9, page 7, the Lummus report lists "*a number of issues worthy of investigation*" and goes on to say "*it is recommended that NP, the CA and other interested stakeholders propose options for treatment of NP curtailable load that address the concerns discussed above*". Hydro confirms in CA-NLH-174 that it has not proposed changes in the treatment of NP's curtailable load at this GRA. It has been six years since the report in Exhibit 11 was completed. Hydro has finally submitted a GRA and is now telling the Parties to propose options. It is inefficient and unrealistic to expect the Parties to propose options when as stated above it is necessary to test cost of service implications. It would require that each Party design a curtailable tariff and run its own cost of service studies to test it. The Parties cannot be expected to address this issue during negotiations when Hydro has put nothing on the table to discuss in spite of its commitment to do so in 2008.

It is difficult to understand Hydro's handling of this matter when one considers: 1) its Generation Planning Issues Report dated November 2012 lists as a key issue for Hydro to deal with in the near term: "*Reduction Initiatives – Hydro must continue to take into* *account the consideration of demand reduction initiatives through demand management programs and rate design,*" (IC-NLH-16 Attachment 1, page 5 of 43)[1] and 2) NP's curtailable load has been called upon on two occasions since 2008, both in January 2013, and on both occasions the request to interrupt curtailable load was denied (see IC-NLH-72)[2]. It would appear from CA-NLH-176 that in the first instance the request was denied because of the timing of the request, and because the arrangements could not be made to be in place in time for the evening peak. On the second occasion, the request was denied owing to the number of requests to curtailable customers that had already taken place. In other words, on the two occasions that the curtailable load would have benefitted the system it was not available because of the poor design, or Hydro's lack of understanding of the design. This should have triggered a response from Hydro, as should have its agreement in 2008 to review the curtailable service rate design. Instead of pursuing demand reduction initiatives such as curtailable/interruptible load as recommended in its 2010 Generation Planning Issues Report, Hydro was forced to pursue an interruptible contract this past winter with CBPP during an emergency situation when the system was under considerable stress.

It is understood that Hydro has initiated discussions with its other Industrial Customers on potential interruptible rate options (see Hydro report "A Review of Supply Disruptions

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[1] This was also listed as a key issue in a Hydro planning report issued in July 2010 entitled Generation Planning Issues 2010 July Update (Executive Summary, page ii).

[2] In its response to PUB-NLH-127 relating to the Outage Inquiry, Hydro indicates that it called upon NP Curtailable Service customers twice in December 2013 and on both occasions, 8 to 10 MW were made available. However, as indicated in the GRA Application Volume II, Exhibit 11, pages 25/26, an increased number of curtailment requests for both economic and system reasons may result in reduced participation and reduced curtailable load in the long term.

and Rotating Outages: January 2-8, 2014", dated March 24, 2014, page 54 of 55). While an interruptible rate option for the ICs may be desirable for system reliability and security reasons, one on one discussions such as these held in private have the appearance of negotiated rates, and are inconsistent with the monopoly market format in this Province. Rates should be Board-approved and should be based on a transparent cost/benefit analysis with full review and comment by the Parties. This GRA provides such a forum.

Hydro should file within the context of this GRA an interruptible rate option for the ICs which ensures consistent treatment with the NP curtailable service option, includes an assessment of the interruptible load contract with CBPP in light of the generation credit (see below), and includes an assessment of the fairness of the CBPP interruptible contract given that none of the other ICs were coincidentally offered the same rate option. The IC interruptible rate filing should recognize that the ICs are already receiving a rate subsidy from the small customers in the Province (proposed in the 2013 GRA consistent with OC2013-089) - it would be prudent that the small customers get something in return for paying this subsidy.

In summary, I recommend that Hydro, in cooperation with NP and the ICs, file for the Board's consideration curtailable/interruptible rate designs for NP curtailable service customers and the ICs. The NP curtailable service rate design should address the design issues raised in Exhibits 9 and 11, and identify the implications in the 2013 cost of service study. The IC interruptible rate design should include an assessment of the impact of the interruptible contract on the CBPP generation credit, ensure consistent treatment among the ICs and with the NP curtailable service rate option, and should recognize that the ICs are already receiving a rate subsidy from the small customers in the Province. The curtailable/interruptible rate filing should be consistent with the 2013 GRA and cost of service, and I recommend it form part of the Board's Order on the 2013 GRA.

8. Corner Brook Pulp & Paper (CBPP) Generation Credit

In the GRA Application Volume II Exhibit 4 Hydro documents the results of its study on the Corner Brook Pulp and Paper (CBPP) generation credit. A pilot supply agreement was approved by the Board in April 2009 where under normal circumstances CBPP will be free to operate its generating units to efficiently convert water to energy. The intent is to allow operation of Deer Lake Power generation at its most efficient load settings. In the 2013 GRA, Hydro proposes that the supply agreement with CBPP be permanently instated (see page 1 of Exhibit 4).

Hydro summarizes the overall benefits of the new supply agreement with CBPP on page 3 of Exhibit 4. Based on the energy benefit applied to the 2013 Test Year cost of service allocation, the benefit to all consumers is estimated at $663,000 shared as follows: $426,000 for NP, $203,000 for the ICs and $34,000 for Hydro Rural customers. In CA-NLH-56 Hydro estimates the savings going forward at about $594,000 annually assuming 3.7 GWh annual energy savings at Deer Lake displacing oil-fired generation from Holyrood.

There are a number of issues associated with Hydro's analysis of the CBPP supply agreement, as follows:

a) ***Benefits are Overstated***: Hydro acknowledges in its response to CA-NLH-56 that marginal costs of demand and energy from the Lower Churchill Project are not available at this time. However, based on the marginal energy cost estimates in CA-NLH-171, the expectation following Muskrat Falls commissioning in 2017 is that the marginal cost of energy will be reduced, as will the savings from the new supply agreement with CBPP.

b) ***Benefits are not Shared Equally***: The benefits which are shown to be entirely associated with energy (CA-NLH-56) are not shared on the basis of energy ratios as stated in CA-NLH-62. According to CA-NLH-57, NP has 87% of the energy demand on the system (before losses), but receives only 64% of the benefits. The IC class with 6% of the energy demand on the system (before losses) receives 31% of the benefits, while rural customers with 7% of the energy demand on the system (before losses) receive 5% of the benefits.

c) ***Costs Exceed Benefits***: The benefits to CBPP of the proposed supply agreement are identified in CA-NLH-59. In the 2014 through 2017 period, inclusive, CBPP will save an average of $641,700 annually while customers are forecast to see cost savings of about $600,000 over the same period (see CA-NLH-56). These cost savings are based on the higher marginal cost of energy prior to Muskrat Falls.

d) ***Fairness Issues***: CBPP and other ICs are receiving subsidized rates over a three-year period owing to OC2013-089. NP customers are being forced to fund the IC rate subsidy. This raises issues of fairness and the appropriateness of locking in additional savings to CBPP on top of the subsidized rate when the value of the proposed supply agreement to other customers on the system does not appear to exceed the costs, especially following Muskrat Falls commissioning.

e) ***Benefits Analysis does not Consider Recent Events***: Hydro has recently entered into an agreement with CBPP for 60 MW of interruptible power (see PUB-NLH-48 of Island Interconnected System Supply Issues and Power Outages) owing to the outage events of the 2013/14 winter. The agreement is for progressively increasing blocks of capacity from CBPP's generation (20 MW, 40 MW and 60 MW). Payment is made for energy received during the period of capacity assistance, and for the highest MW interruption requested. Hydro has also agreed to pay a capacity fee of $63,000 per month for each winter month. It is understood that Hydro is negotiating extension of the agreement with CBPP and negotiating with other ICs for interruptible power contracts (see PUB-NLH-62 of Island Interconnected System Supply Issues and Power Outages). Hydro has not filed in the 2013 GRA information relating to the interruptible agreement and its impact on the CBPP generation credit and associated benefits.

In light of the above, I recommend that the Board deny Hydro's proposal to permanently instate the supply agreement with CBPP. I recommend that the Board direct Hydro to file a study of the supply agreement in its entirety taking into consideration the new interruptible component of the contract, the subsidy being received by the ICs owing to the IC rate phase-in, and the reduced value of energy following commissioning of Muskrat Falls. I recommend the study consider the pros and cons of separate contracts with Deer Lake Power generation and CBPP. The contract with Deer Lake Power generation would be similar to other power purchase agreements with generators on the Island Interconnected System, while the agreement with CBPP would be similar to other supply agreements with Industrial Customers on the Island Interconnected System. This would increase transparency, and optimize the conversion efficiency of water to electrical energy at the Deer Lake Power facility. It would also give Hydro a measure of control over the facility during system emergencies when it is most needed, such as the outage events during the past two winters. The filing should be consistent with the 2013 GRA and cost of service, and I recommend that it form part of the Board's Order on the 2013 GRA.

9. Cost of Service – Classification of Wind Generation Purchases

Since the last GRA, two new sources of wind energy have been installed on the Island Interconnected System at St. Lawrence and Fermeuse (see GRA Application Volume I, page 1.6, lines 10-11). The characteristics of wind generation can be quite different from other forms of generation owing to the intermittency of the primary fuel source – the wind. According to the cost of service study (GRA Application Volume II, Exhibit 13, Schedule 4.4, page 1 of 1) Hydro has classified purchases from non-utility generation including wind generators according to system load factor, roughly 45% as capacity-related and 55% as energy-related.

In NP-NLH-279 Hydro was asked if the power purchase costs from wind should be classified as 100% energy-related in the cost of service study. Hydro's response is that wind farms are predominantly an energy source, but they can provide capacity as well. In NP-NLH-280 Hydro provides classification practices for wind power purchases used in other jurisdictions. Nova Scotia uses a 9%/91% split between capacity and energy. BC Hydro classifies 100% of all IPP purchases to energy, but proposes to review this at its next rate application in 2015. Saskpower uses a 20%/80% split between capacity and energy, while Colorado uses a 12%/88% split between capacity and energy. Various Regional Transmission Operators classify as capacity-related costs ranging from 8.7% to about 35%. The point is that most jurisdictions classify a portion of wind generation costs to capacity with the amount varying significantly from one jurisdiction to another, but in all cases considered, the classification as capacity-related is much less than the 45% figure used by Hydro in its cost of service study. It does not appear as though Hydro has undertaken a detailed study on how to fairly classify the costs of purchases from the wind farms in the cost of service study for the Island Interconnected System. This raises fairness issues.

I recommend that Hydro file a study for the Board's consideration on the appropriate capacity/energy classification of purchases from wind generation on the Island Interconnected system for use in the cost of service study. The filing should be consistent with the 2013 GRA and cost of service, and I recommend that it form part of the Board's Order on the 2013 GRA.

10. Rural Rate Subsidy

The Rural Rate Subsidy has reached alarmingly high levels, adding 14% to the bills of NP (see GRA Application Volume II, Exhibit 3, Schedule 1.2, page 2 of 6), and 44% to the bills of Labrador Interconnected Customers (see GRA Volume II, Exhibit 3, Schedule 1.2, page 6 of 6).

OC2003-347 (Attachment 1 to CA-NLH-38) states that the rural deficit is to be collected from NP and Labrador Interconnected customers. However, the revenue to cost ratios deriving from the rural deficit allocation methodology are clearly unbalanced, and are expected to remain so. As shown in LWHN-NLH-18, under the current rural deficit allocation methodology the revenue to cost ratio for Labrador Interconnected customers is forecast to remain at 1.35 or more through the end of 2016. The revenue to cost ratio for NP is expected to gradually decline to 1.11 by 2016.

Rates for the Labrador Interconnected customers have increased by 36% since the last GRA (see CA-NLH-4) including a proposed increase of 23.3% in this GRA (see Table 4.4 of GRA Application Volume 1). Admittedly, rates for Labrador Interconnected customers started at a low level, but 31% (0.44/1.44) of the proposed rate is attributable to the rural rate subsidy, a cost over which Labrador Interconnected customers have no control. The cost of the rural deficit per customer is shown in the table below. As can be seen, the average annual contribution per Labrador Interconnected customer is $631, about three times the average annual contribution per NP customer of $210.[3] As Hydro states on page 5 of 8 in CA-NLH-166 (Revision 1, April 22, 1014), "*The current methodology results in materially higher customer billing impacts for Labrador Interconnected Customers primarily because they have higher electricity usage as a result of living in an area of the Province where the climate is materially colder*".

Customer	Number of Customers	Contribution to Payment of Rural Deficit [1]	Average Contribution per Customer
Newfoundland Power	256,000 [2]	$53,882,421	$210
Labrador Interconnected	10,835 [3]	$6,842,261	$631
Total	266.835	$60,724,682	$228

Notes: 1) Exhibit 13, Schedule 1.2.1, page 2 of 2

2) NP website: http://www.newfoundlandpower.com/AboutUs/

3) Exhibit 13, Schedule 1.3.2, page 3 of 3

Hydro states on page 6 of 8 in CA-NLH-166 (Revision 1, April22, 2014) "*Hydro believes that the current methodology does not provide a reasonable sharing of the rural deficit between Labrador Interconnected Customers and Newfoundland Power Customers*". I agree, and have a number of points to make relating to the Board's 21 year old report on Hydro's Cost of Service Methodology and the allocation of the rural deficit (see February

[3] CA-NLH-166 (Revision 1, April 22, 2014) Table 2 shows similar average costs per customer.

1993 report on Hydro's Cost of Service Methodology, PUB-NLH-113, Attachment 1), as follows:

a) ***Allocation of Large Subsidies***: As stated on page 51 of the Board's February 1993 report, "*The deficit instead falls out of the operation of a system that is physically, for the most part, and financially isolated from the three main classes in the Cost of Service, NP, the Industrials and Labrador Interconnected.*" On page 53, the Board points out that "*as a component of a Cost of Service and basis for pricing under a cost recovery system, the allocation for rural deficit represents the allocation of another group of customers' cost of service*". Finally, on page 55 the Board states "*There does not appear to be any competency constraint in the methodology chosen to allocate the rural deficit either by revenue to cost ratio of one, energy allocation or some combination of revenue, energy or demand*". To summarize the Board's points, the rural deficit represents a cost to be recovered by Hydro that is in no way related to the cost of supply of the customers required to pay the subsidy, and there is no "accepted" methodology in the industry for allocating the rural deficit.

b) ***Proposed Deficit Recovery Methodologies***: Three methods of cost recovery for the rural deficit were proposed by the interveners at the 1993 review. Hydro proposed allocation on the basis of revenue requirement (see page 55) which would result in the same revenue to cost ratio for all subsidizing customer classes regardless of the system from which they are supplied. NP pointed out that there is no basis on which non-rural customers can have the deficit allocated in accordance with causality, so fairness of the ultimate result can assist in the selection of a methodology. NP proposed that the deficit be allocated on the basis of 50% energy and 50% revenue requirement (see page 56). The Industrial Customers proposed allocation of the rural deficit on the basis of plant cost. The Town of Labrador and the Town of Wabush both supported Hydro's proposed methodology of allocation on the basis of revenue requirement. The Towns put forth the argument that allocation according to revenue requirement is in accordance with sound regulatory principles.

c) ***Board Consultant's Proposed Recovery Methodology***: As the Towns pointed out, allocation of a cost according to revenue requirement is a commonly used allocator in cost of service. On the other hand, plant cost as proposed by the ICs is also a commonly used allocator in cost of service, and so is energy as proposed by NP (50/50 split in combination with revenue requirement). The Board's consultant, Mr. Baker, proposed a method that "*involves a preliminary split of costs between Newfoundland and Labrador on the basis of demand, energy and customer number*". His proposed methodology first classifies the deficit by proration on the classified costs of subsidizing classes. Next, the classified totals are divided by the use characteristics of the subsidizing classes as a whole to obtain unit classified costs. These unit costs are then used to allocate between Island and Labrador Systems." (see IN-PUB-2, page 29, lines 13 to 21 of Mr. Baker's testimony attached to the response). While revenue requirement, plant and energy are commonly used allocators in cost of service, I am not aware of any jurisdiction that uses the allocation methodology proposed by Mr. Baker, and accepted by the Board, and note that no reference was made to regulatory precedents in either the Board's report or Mr. Baker's testimony. Mr. Baker himself states "*I am not aware of any generally accepted cost of service methodology for dealing with this particular situation. In finding the best solution, judgment must play a part*" (see IN-PUB-2, page 28, lines 2 to 4 of Mr. Baker's testimony attached to response).

d) ***Board's Position on Proposed Recovery Methodologies***: The Board states (see PUB-NLH-113, Attachment 1, page 61) that the Hydro, NP and IC proposed methods of deficit allocation are not in accordance with generally accepted cost of service principles, and that the NP and IC proposals use arbitrary methods. However, in my opinion these methodologies are just as much in accordance with generally accepted cost of service principles and not any more arbitrary than the methodology proposed by the Board's consultant and accepted by the Board.

e) ***Criterion for Deficit Allocation***: A criterion for allocating the rural rate deficit that does not appear to have been considered in the 1993 study is allocation in a manner that minimizes the impact on the price signal of the subsidizing customers. Rates based on the cost of service represent the correct price signal in that rates reflect the costs that customers impose on the system. In 1993 the Board's consultant states a number of times in his testimony (see IN-PUB-1) that he favours cost-based rates. Most rate design experts do, but once it is accepted that the rural deficit must be collected from the subsiding customers (i.e., NP and Labrador Interconnected customers), then a guiding principle is that the deficit be applied in a manner that least distorts the price signal. Recovery of the rural rate deficit forces distortion of the rates of the subsidizing classes because their rates are based on full cost recovery, plus the rural deficit. This means the principle of cost based rates cannot be met; however, the rural deficit can be applied to the subsidizing classes in a manner that minimizes the impact on the price signal.

f) ***Assessment of Alternatives on Basis of Price Signal Impacts:*** As can be seen in CA-NLH-228 Attachment 1, of the allocation methodologies proposed at the 1993 review, allocation based on revenue requirement would result in the same revenue to cost ratio of 1.15 for both NP and the Labrador Interconnected customers. The current methodology results in revenue to cost ratios of 1.44 (ranging from 1.37 to 1.63 depending on the customer class) for the Labrador Interconnected customers and 1.14 for NP. The allocation methodology based on the NP proposal of 50% revenue requirement and 50% energy sales results in a revenue to cost ratio of 1.14 for NP, and revenue to cost ratios ranging from 1.1 (street and area lighting) to 1.33 (General Service over 1000 kVA) on the Labrador Interconnected system. The least amount of distortion to the price signal is obtained by allocation on the basis of revenue requirement. The current rural deficit allocation methodology results in the greatest distortion of the price signal when compared to the other methodologies proposed at the 1993 review.

g) ***Alternatives Proposed by Hydro:*** In CA-NLH-166 (Revision 1, April 22, 2014), pages 6 to 8, Hydro proposes two alternative methodologies to the methodology currently in use for allocation of the rural deficit. The first is on the basis of revenue requirement (as proposed by Hydro in 1993), and the second is on the basis of number of customers. The cost and rate impacts on customers are summarized in tables 5 and 6 and reproduced below. As can be seen, both of the alternative methodologies provide more comparable customer cost impacts than the current methodology. Further, both of the alternative methodologies result in more equitable rate impacts than the current methodology.

	Current Method	Revenue Requirement	Number of Customers
Average Annual Cost Per Customer			
Labrador Interconnected	$630.39	$208.31	$227.88
Newfoundland Power	$210.79	$228.69	$227.88
Impact on Proposed Rates			
Labrador Interconnected	25.1%	-(0.6)%	0.6%
Newfoundland Power	-(4.8)%	-(3.7)%	-(3.8)%
Customers of Newfoundland Power	-(3.2)%	-(2.5)%	-(2.5)%

h) ***The Size of the Rural Rate has Reached Extreme Levels***: The above discussion is based on the assumption that the subsidizing parties must pay the full amount of the rural deficit. While it is important that the subsidy be transparent and based on accepted cost of service principles, the size of the rural rate deficit and the requirement that NP and Labrador Interconnected customers pay the full amount of the deficit goes well beyond what has been accepted as normal practice in the industry. As discussed in PUB-NLH-339, Hydro filed as part of the 2003 GRA a discussion paper for the Minister of Mines and Energy on the rural deficit which included practices in other jurisdictions. In PUB-NLH-339 Attachment 1, Hydro includes a copy of the Discussion Paper which shows (page 2 of 14) that the deficit increased from $28.9 million in 1992 to $38.8 million in 2002. Hydro correctly predicted that the deficit would continue to increase – it is now forecast to be $60.5 million in 2014, and $62 million in 2017 (see CA-NLH-207). As Hydro states (on pages 8 and 9 of 14), the rural deficit per customer falls within the range experienced by other utilities in Canada. However, with the small population base in the Province, Hydro's operating deficit for its rural areas at the time of the study was 8.8 % of revenues from electricity sales, far larger than in Quebec at 1%, BC at 1%, and Manitoba and Ontario at about 0.1% of revenue from electricity sales. The operating deficit in the Province based on rates proposed in the 2013 GRA is 10.7% of revenue from electricity sales (based on rural deficit of $60.7 million (GRA Volume II Exhibit 13, Schedule 1.2.1, page 2 of 2) and revenue from sales of $568.1 million (GRA Application Volume I, Finance Schedule 1, page 1 of 11)).

i) ***Board's Position on Payment of Rural Deficit***: PUB-NLH-339 Attachment 1 (pages 10 and 11 of 14) references a number of statements attributable to the Board relevant to the rural rate deficit, as follows:

- In its 2002 Order the Board stated "*The question of who should share in this continuing liability, either rural customers, other customers, NLH and/or Government, may become a central issue for the Board in the future*".
- "*Depending on the level of subsidy paid by one customer to support equitable rates for another customer, rates may be judged unreasonable and discriminatory to the subsidizing customer*".
- "*Under these circumstances, the only effective means of implementing the provincial power policy is to transfer some or all of the rural deficit to NLH or its shareholder, Government*".
- "*The Board is not inclined to adjust NLH's regulated 3% ROE in this Application*".
- "*The Board feels strongly, however, that discussions involving NLH and Government around future funding options for the rural deficit should constitute part of the evidentiary record*".

The Board's statements remain relevant today with the exception that Hydro's regulated 3% ROE is no longer the case because OC2009-063 dated March 17, 2009 directs that Hydro's target return on equity be the same as that set for NP, currently 8.8%, and that its rate of return apply to the entire rate base "*including amounts used solely for the provision of service to its rural customers*". Hydro proposes in the 2013 GRA that it receive an 8.8% ROE and that its rate of return apply to the entire rate base beginning January 1, 2014.

In summary, the rural rate deficit has become a significant burden. It results in unreasonable and discriminatory rates for the subsidizing customers. Now that Hydro has a mandated ROE commensurate with that of NP, I recommend that the Board consider directing a portion of Hydro's return toward payment of the rural subsidy, a subsidy mandated by Government, Hydro's shareholder.

Further, if rural rates continue to be subsidized by NP and Labrador Interconnected customers, I recommend that greater emphasis be placed on the fairness of the allocation methodology, particularly since there is no generally accepted cost of service methodology for dealing with this situation (as stated in IN-PUB-2, page 28, lines 2 to 4 of Mr. Baker's testimony attached to the response). Based on the principles of fairness and minimization of the impact on the price signal, allocation of the deficit on the basis of revenue requirement or number of customers are both preferred over the current allocation methodology. On this basis, I recommend the Board order that the rural rate deficit amount that is to be paid by NP and Labrador Interconnected customers be allocated on the basis of revenue requirement or number of customers.

11. Abandonment of Wheeling Rate

In the GRA Application Volume 1 (page 4.6, lines 17 to 18) Hydro states "*As there are no remaining ICs to whom the availability clause of Hydro's former Wheeling Rate applies, Hydro is proposing to no longer offer this rate*". In CA-NLH-29, Hydro indicates there is a possibility that a wheeling rate may be required in the future for another customer, but no such requirements are known at this time. Hydro goes on to say that if a wheeling rate is required in the future, an application will be put forward at that time.

I do not believe that this explanation justifies abandonment of a rate that is tried and tested. If the need for the rate arises in the future, it would be much simpler to use a rate that is already available than to submit an application for a new rate. I recommend that the Board direct Hydro to maintain the wheeling rate until justification arises in the future to replace it with something different.

12. Key Performance Indicators (KPIs)

In the GRA Application Volume 1 (page 4.28, lines 12 to 14), Hydro requests the Board's approval for altering or amending Order No. P.U. 14(2004) so that functionally oriented financial Key Performance Indicators are not required to be provided on a forecast basis. Hydro's justification (page 4.28, lines 1 to 3) is that its functionally oriented financial KPIs require a COS study to allocate costs among systems and functional areas.

Hydro has rates based on a COS study that is seven years old, so it is not clear why there is a problem basing a financial performance target on an older COS study provided results relative to the target are recorded in a consistent manner. It is useful for the Parties and the Board to see how Hydro is performing relative to targets, particularly when Hydro's target return on equity is fixed by way of Government directive (see OC2009-063). I recommend that the Board direct Hydro to file an approach to identifying functionally-oriented financial targets and reporting in a consistent manner without incurring the costs associated with undertaking a COS study.

Hydro's residential customer satisfaction has slipped dramatically from about 92% in 2010 to 80% in 2012 (see GRA Application Exhibit 2, pages E32 and E33). This compares to Hydro's target of ≥90%. Hydro attributes the slippage in customer satisfaction to reliability of service (page E33 of Exhibit 2). In CA-NLH-51, Hydro indicates that it has not finalized targets for customer satisfaction in 2013 and 2014, but is "*developing a five-year customer service strategy focused on improving the services it provides to customers. The strategy is anticipated to be completed in 2014.*"

I cannot over-emphasize the importance of this initiative in light of OC2009-063 which directs that Hydro's target return on equity be the same as that set for NP. With the Government directive, Hydro's incentive to provide superior customer service is reduced, so it will be important for the Board to closely monitor Hydro's performance. The KPI report provides important insights in this regard.

I recommend that the Board direct Hydro to submit a scope of work and time-bound plan for development of a strategy for improving customer service. I recommend that the strategy include performance targets as a means for gauging progress annually, and once completed, be submitted to relevant stakeholders for review and comment.

This concludes my Pre-filed Evidence.

Exhibit CDB-1

C. Douglas Bowman

Background and Qualifications

Profession	*ENERGY CONSULTANT*
Nationality	Canadian Citizen U.S. Resident
Years of Experience	37
Education	M.S./1977/Electrical Engineering/State University of New York, Buffalo, NY B.S./1975/Electrical Engineering/State University of New York, Buffalo, NY
Key Qualifications	Mr. Bowman has 37 years of experience in the power industry both domestically and internationally. His primary areas of expertise include electricity services costing and pricing and power sector restructuring, regulation and markets. Mr. Bowman has played a leading role in consulting projects in Canada, Armenia, Australia, Central America, China, Colombia, Dutch Antilles, Egypt, Georgia, Ghana, India, Indonesia, Macao SAR, Macedonia, Mexico, the Middle East, Mongolia, Pakistan, the Philippines, Russia, Saudi Arabia, Serbia, South Korea, Taiwan, Thailand, United States and Vietnam.

Expert Testimony at Newfoundland and Labrador Hydro's Application Concerning the Rate Stabilization Plan
Provided expert written testimony on issues related to Hydro's 2009 Application on the rate stabilization plan components of the rates to be charged Industrial Customers.

Expert Testimony at Newfoundland Power Inc.'s Rates Submission
Provided expert written and oral testimony on issues related to cost of service, rate design and distribution quality and reliability of service standards at Newfoundland Power's 2008 General Rate Application.

Expert Testimony at Newfoundland and Labrador Hydro's Rates Submission
Provided expert oral and written testimony and participated in negotiation sessions on issues related to cost of service, rate design and regulation at Hydro's 2006 General Rate Proceeding.

Expert Testimony at Newfoundland and Labrador Hydro's Rates Submission
Provided expert oral and written testimony and participated in mediation sessions on issues related to cost of service, rate design and regulation at Hydro's 2003 General Rate Proceeding.

Expert Testimony at Newfoundland Light & Power's Rates Submission
Provided expert written testimony and participated in mediation/technical sessions on issues related to cost of service and rate design at Newfoundland Light & Power's 2003 General Rate Application.

Expert Testimony at Newfoundland and Labrador Hydro's Rates Submission
Provided expert oral and written testimony related to cost of service and rate design issues at Hydro's 2001 General Rate Proceeding.

Expert Testimony at Newfoundland Light & Power's Rates Submission
Provided expert oral and written testimony related to cost of service and rate design issues at Newfoundland Light & Power's 1996 General Rate Proceeding.

Expert Testimony at Nova Scotia Power's Rates Submission
Provided expert oral and written testimony related to cost of service and rate design issues. Recommended and designed time-of-day rates for all customer classes and designed an alternative interruptible rate design for large industrial customers.

Expert Testimony at Nova Scotia Power's Rates Submission
Provided expert oral and written testimony regarding an Industrial Expansion rate design. Recommended approval of rate with modifications and submitted two alternative rate designs for approval including a real-time surplus power rate and a time-of-day expansion rate.

Cost of Service and Cost Reducing Rate Design Study
On behalf of the Nova Scotia Utility and Review Board, reviewed Nova Scotia's cost of service study and developed rate designs consistent with Nova Scotia Power's integrated resource plan for all customer classes. Report was filed with Board, and reviewed as part of hearing on utility's subsequent rate submission.

Economic Policy Reform and Competitiveness Project – Mongolia
Assisted with the setup and training of the new regulatory commission in Mongolia. Developed tariff reform plan that was accepted by the regulatory commission for implementation. Developed incentive based power purchase agreement for sales of generating company capacity and energy to the transmission company. Developed market rules for governing competitive electricity market.

Electricity Market Reform in Macedonia
Participated in development of competitive electricity market design for Macedonia consistent with European Union market design. Assisted with development of Market Rules to govern operation of the competitive electricity market.

Competitive Electricity Market Design – Taiwan
Developed competitive market design for electricity sector in Taiwan. Drafted market governance documents including Market Rules and Grid Code. Managed market modeling component of project which simulated market operation under wide range of scenarios.

Alberta RTO Evaluation Project
Developed strategy related to preferred business relationship between the Alberta Regional Transmission Organization and RTO West to ensure Alberta's electricity needs are met by a competitive market. The project participants included the Alberta Department of Energy, ESBI Alberta Limited, and the Power Pool of Alberta.

Detailed Market Design and Market Rules Development, Western Australia
Served as project manager providing advice to the Government of Western Australia with regard to detailed market design, market rules development, and market power mitigation. Assisted with the stakeholder process, drafted position papers on various design topics, drafted market rules consistent with a bilateral contracts market, and designed a market power mitigation program.

Market Assessment of Generating Company in Korea
Provided advisory services to a client interested in submitting a bid for the purchase of a large generating company in Korea. Served as Project Manager for the market valuation component of the project.

Expert Testimony in Kansas Civil Case Concerning IPP Development
Provided expert testimony concerning the independent power producer (IPP) programs in India and Colombia. The testimony related to the difficulties and hurdles that must be overcome in order to successfully develop an independent power project in a developing country.

Market Power Mitigation Strategy for Generating Company in Korea
Provided advisory services to a large generating company in Korea relating to a market power mitigation strategy. Served as project manager. The project included market simulation to determine if the generating company would have market power in the new competitive market, and if so, if its market power were any greater than other generating companies participating in the market.

Advisory Services to World Bank on Regional Market Design among Arab Countries: Conducted a review of the status of market reform in the Arab countries and designed a competitive regional electricity market and road map for implementation of the market and ultimately gain access to markets in the surrounding region. Developed governance documentation for the regional electricity market including a General Agreement, Market/Commercial Rules and a Grid Code.

Advisory Services on Transmission Tariff Development in Georgia: Provided advice to Government of Georgia on behalf of USAID on transmission tariff development. The project included a comparison of current practice in Georgia to best practice in the European Union and provided recommendations for bringing current practice up to EU standards.

Advisory Services to World Bank on Regional Energy Integration in Middle East and Surrounding Area: Provided advice to Government of Saudi Arabia on behalf of World Bank on regional energy integration of GCC countries (Saudi Arabia, Kuwait, Bahrain, Qatar, UAE and Oman), as well as a select number of other countries offering trade opportunities for Saudi Arabia including Egypt, Iraq, Jordan, Syria, Lebanon, Iran, Turkey and the EU. Advice included assessments of legal, regulatory and policy relating to international energy trade, energy demand and supply balance, electric transmission interconnection including HVAC and HVDC, and pipeline capacity to support trade.

Advisory Services to World Bank on Potential Egypt – Saudi Electrical Interconnection: On behalf of Government of Saudi Arabia, conducted evaluation of potential HVDC electrical interconnection between Saudi Arabia and Egypt.

Advisory Services on Electricity Market Design in Serbia
Developed a high-level, phased design for the internal Serbian electricity market consistent with the EU Directive. The project intent was to provide institutional support to the Ministry of Mining and Energy to facilitate the phased development of the internal electricity market with competitive bilateral contracts taking into account Serbian Energy Policy, the draft Energy Law, European Union requirements and the Athens Memorandum 2002.

Expert Testimony in California Civil Case Concerning Breach of Contract
Provided expert testimony concerning the value of a company based on revenues generated less costs to manage and operate the business. Revenues were derived from a contract for energy services covering steam and electricity sales to an industrial client and its power purchase agreement covering electricity sales to a utility.

Workshop on Transmission Planning in a Competitive Power Market
Conducted workshop on transmission planning for proposed RTO West in Portland, Oregon. Workshop covered transmission planning responsibilities of Regional Transmission Organizations under FERC Order No. 2000 and experience with domestic independent system operators and international transmission organizations. Reliance on market mechanisms for transmission expansion was emphasized at workshop.

Workshop on Transmission Pricing in a Competitive Power Market
Conducted workshop on transmission pricing for proposed RTO West in Portland, Oregon. Workshop covered transmission pricing in Regional Transmission Organizations under FERC Order 2000 and experience with domestic Independent System Operators and international transmission organizations. Workshop addressed transmission services such as network, connection, import, export, and point-to-point service, and cost recovery such as postage stamp, zonal and nodal pricing.

Development of Terms and Conditions for Transmission Tariff
Assisted Ontario Hydro Services Company with development of terms and conditions for its new transmission tariff. The terms and conditions were filed with the regulatory authority as part of the utility's application for approval of the new tariff. Also assisted with preparation of responses to various discovery questions related to the tariff.

International Survey of Transmission Rates and Services
Conducted a survey of transmission rates and services provided in various domestic and international jurisdictions. Survey conducted in support of submission by Ontario Hydro Services Company to Ontario Energy Board on its new transmission tariff. Survey topics included: services offered such as network, point-to-point, connection, import and export service; cost recovery such as postage stamp, zonal and nodal pricing; treatment of generation; and transmission planning.

Feasibility Study of Merchant Co-generation Project
Participated with a team of consultants on a feasibility study for development of a merchant co-generation facility to sell power into the wholesale market and steam to the industrial plant. Directed market studies including analyses of forecasts for electricity demand, new generating plant construction, generation costs, market bid strategies, fuel costs, utility avoided costs, etc.

Advice to Mid-west Cooperative Concerning Role in Deregulated Power Market
Provided advice to a mid-west cooperative on positioning itself for a deregulated power market. Advice included the cooperative's future power purchasing strategy, transmission and distribution construction and operations and maintenance strategy and how it should position itself to compete in the future deregulated power market.

Experience

Independent Consultant, Warrenton, VA 2005 to Present

Nexant, Inc., Washington, DC 2004
Executive Consultant

KEMA Consulting, Fairfax, VA 1999 to 2004
Executive Consultant

Pace Global Energy Services, Fairfax, VA 1998 to 1999
Director, Power Services

International Resources Group, Ltd. (IRG), Washington, DC 1995 to 1998
Senior Manager, Energy Group

CSA Energy Consultants, Arlington, VA 1994 to 1995
Vice President (1995); Senior Manager, Power Supply Analysis (1994)

Ontario Hydro, Toronto, Ontario, Canada 1977 to 1993
Industrial Service Advisor, Field Support Services Department, 1992-1993

Senior Rate Economist, Rate Structures Department, 1990-1992

Planning Engineer, Demand/Supply Integration, System Planning Division, 1988-1990

Senior Engineer, Resource Utilization, Power System Operations Division, 1987-1988

Planning Engineer, BES-Resources Planning, System Planning Division, 1981-1987

Assistant Planning Engineer, Transmission System Planning Department, 1979-1981

Engineer-in-Training, 1977-1979

Professional Affiliations

Professional Engineers of Ontario